POULTON & YORDAN
ATTORNEYS AT LAW

RICHARD T. LUDLOW

January 31, 2006

H. Roger Schwall
Assistant Director
Division of Corporate Finance
Mail Stop 7010
United States Securities and Exchange Commission
Washington, D.C. 20549

Re: BMB Munai, Inc.
Registration Statement on Form SB-2
Filed October 21, 2005
File No.: 333-129199

Form 10-KSB/A for the year ended March 31, 2004
Filed October 5, 2005
File No. 000-28638

Dear Mr. Schwall:

At the request of the management of BMB Munai, Inc., (the "Company" or "BMB Munai") and further to my conversations with Mr. Murphy and Ms. Moncada-Terry we are responding to comments raised by the staff at the Securities and Exchange Commission in your letters dated November 23, 2005 and November 30, 2005. Following are the responses to your comments.

LETTER OF NOVEMBER 23, 2005

Selling Security Holders, page 14
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1. Disclose how the securities being registered for resale were acquired by the selling security holders.

The securities being registered for resale were acquired by the selling security holders directly from the Company in either the private placement of shares concluded by the Company in July 2004 or March 2005, pursuant to exemption 4(2) of the Securities Act and/or Regulation S.

POULTON & YORDAN   TELEPHONE: 801-355-1341
324 SOUTH 400 WEST, SUITE 250   FAX: 801-355-2990
SALT LAKE CITY, UTAH 84101   POST@POULTON-YORDAN.COM

If the staff deems it necessary, the Company will add disclosure of this information to the amended SB-2 registration statement.

2. Identify as underwriters all selling security holders who are registered broker-dealers, unless you can confirm to us that such selling security holders received their shares as compensation for investment banking services.

Each selling security holder has confirmed that it is not a registered broker-dealer.

Form 10-KSB/A for the year ended March 31, 2004
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Controls and Procedures, page 30
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1. We note that, in addition to your disclosure that the disclosure controls and procedures were not effective as of the end of the reporting period covered by the amended report, you include disclosure indicating that "your disclosure controls and procedures are now effective." Revise to expand the disclosure to explain how management has determined that disclosure controls and procedures are now effective. Make similar revisions to your Form 10-QSB/A for the quarter ended December 31, 2004.

We propose to amend the disclosure controls and procedures as follows to explain how management has determined that disclosure controls and procedures are now effective.

"Our chief executive officer and our chief financial officer (the "Certifying Officers") are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rule 13a-15 and Rule 15d-15(e)). Such officers have concluded (based upon their evaluations of these controls and procedures, as more fully discussed in the following paragraphs, as of the end of the period covered by this amended report) that our disclosure controls and procedures are effective as of the date this amended report is filed to ensure that information required to be disclosed by us in this report is accumulated and communicated to management, including the Certifying Officers as appropriate, to allow timely decisions regarding required disclosure. During the period from the time the original report was filed to the time we filed this amended report, we have developed certain internal financial reporting policies and procedures such as thorough review for compliance with requirements by completing appropriate checklists, which to the best of our knowledge and

understanding proved to be effective as of filing of this amended report thus, making us, as the management, believe that disclosure controls and procedures are effective as well."

LETTER OF NOVEMBER 30, 2005

SB-2 filed on October 21, 2005

Summary Historical Reserve and Operating Data, page 4

1. Please remove the dollar signs under the production information for each period shown here and on page 33.

We will remove all dollar signs.

Risk Factors, page 5

A substantial or extended decline in oil and natural gas prices..page 6

2. Please include in this risk factor the fact that you currently receive materially lower prices than world market prices for crude oil and your gas price is substantially lower than that received in North America.

We propose to add the following language to the above referenced risk factor (page 6) to the beginning of the paragraph immediately following the second set of bullet point items:

"Until we are granted an export license from the government, we are limited to selling our production to the domestic market in Kazakhstan. As a result, we currently receive materially lower prices than the world market prices for our crude oil. Similarly, the prices we will receive for the gas we produce will be substantially lower than prices for natural gas received in North America."

3. Please include a risk factor that states under the terms of your current exploration contract you only have the right to produce until the year 2007 and that 94% of your proved reserves are scheduled to be produced after 2007. There is no guarantee whether the current license will be extended or a new commercial exploration and production contract will be granted.

We propose to add the following risk factor to the top of page 8:

We will be unable to produce up to 94% of our proved reserves if we are not able to extend our current contract or obtain a new

contract from the Republic of Kazakhstan, which would likely require us to terminate our operations.

Under our current contract for exploration of hydrocarbons on Aksaz, Dolinnoe and Emir fields, we have the right to produce oil and gas only until July 2007, yet 94% of our proved reserves are scheduled to be produced after July 2007. If we are unable to receive a commercial production contract to which we have the exclusive right to negotiate as per exploration contract terms, or extend our current contract we will lose our right to produce the reserves on our current properties. If we are unable to produce those reserves, we will be unable to realize revenues and earnings and to fund operations and we would most likely be unable to continue as a going concern.

Business and Properties, page 28

Oil and Natural Gas Reserves, page 30

4. You state that Chapman Engineering used oil and natural gas prices in effect during March 31, 2005, which you disclosed was $15.17 for the year ended March 31, 2005. However, the reserve report uses an oil price of approximately $21.00 per barrel, which is 38% higher than the price you disclose in the filing. Please explain this to us.

As dictated by Section 210.4-10(a)(2), the reserve report uses an oil price of $21.00 per barrel because that was the price per barrel of oil in the Kazakhstan domestic oil market on March 31, 2005, the date of the reserve report. By contrast, $15.17 reflects the average price per barrel we received throughout the fiscal year for the oil we sold. As you point out, the price of oil in the Kazakhstan domestic market increased significantly during the period from March 31, 2004 to March 31, 2005, not unlike the significant increases experienced in the world market during the same time period. As a result of the significant price increase during the aforementioned period, the average oil price we realized during the period from March 31, 2004 to March 31, 2005, was lower than the price at March 31, 2005.

Production, page 31
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5. You state that you produced no natural gas during the month of August 2005, however, you disclose 41.7 BCF of proved gas reserves. Please explain this to us.

Please see our response to comment 14 below.

Recent Developments, page 34
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6. You indicate that you have tested several wells such as the Dolinnoe 2 and Emir 1 wells in June 2005. Please disclose the results of this testing and if you think it is representative of the wells' long-term production trends. Along bring this production up to date as possible.

According to the State laws of the Republic of Kazakhstan, the Company is required to test every prospective object on its properties separately, this includes the completion of well surveys on different modes with various choke sizes on each horizon. This testing can take up to three months per horizon.

In the course of well testing, when the transfer from object to object occurs, the well must be shut in, the production activity closes for the period of mobilization/ demobilization of workover rig, pull out of hole, run in hole, perforation, packer installation time, etc. Oil production is temporarily suspended due to well shut down which has the effect of artificially diminishing production rates.

Production rates:

Cumulative total production rate from all intervals tested is shown on the table following the response to this comment.

Aksaz -1

Status: The well is awaiting workover due to technical conditions.

Producing testing intervals: 4,428-4,253m; 4,256-4,257m; 4,261-4,265m; 4,269-4,273m

Prior to workover the single interval production rates were as follows:

139 bpd - 10 mm diameter choke. This production level was registered with paraffin buildup. 252 bpd - 10 mm diameter choke. This production level was registered without paraffin buildup.

Aksaz-4

Status: The well was completed in August 2005.

Producing testing intervals: 4,311-4,299m and 4,294.3-4,292.8m

Current production rates from single interval testing are as follows:

126 bpd - 6 mm diameter choke with paraffin buildup
220 bpd - 6 mm diameter choke without paraffin buildup

Dolinnoe-1

Status: Engaged in test production. The Company plans to increase production from the Dolinnoe-1 well through hydraulic fracturing with acid treatment and, if necessary, horizontal or deviated drilling from existing wellbores will be conducted.

Producing testing intervals: 3,550-3,565m and 3,521-3,532m

Current single interval production rates are as follows:

114 bpd - 6 mm diameter choke with paraffin buildup
189 bpd - 6 mm diameter choke without paraffin buildup

Dolinnoe-2

Status: Engaged in test production. The Company plans to increase production from the Dolinnoe-2 well through hydraulic fracturing with acid treatment and, if necessary, horizontal or deviated drilling from existing wellbores will be conducted.

Producing testing intervals: 3,574.5-3,577m, 3,578.4-3,582m, 3,600-3,609m; 3,611.5-3,613.5m; 3,616-3,627m; 3,640-3,641m

Current single interval production rates are as follows:

126 bpd - 4 mm diameter choke with paraffin buildup

Dolinnoe-3

Status: While testing various intervals, we determined that the current interval from which solid production rates occurred is 24 m, but only 17 m were perforated. After perforation of the 17m a blowout occurred and we could not run in hole with the pipe. We are in the process of killing the well. After killing the well we will clean the bottomhole zone, run in hole with a perforator and will perforate the remaining 7 m in the producing interval. After perforation we will lower tubing and start testing again in order to determine the proper rate.

Producing testing intervals: 3,614.5-3,603m and 3,600.6-3,594.5m

Current single interval production rates are as follows:

756 bpd - 4 mm diameter choke with paraffin buildup
1260 bpd - 8 mm diameter choke with paraffin buildup

Emir -1

Based on logging, 4 prospective objects were identified and perforated and all 4 objects were tested. This well is awaiting a service rig to perform workover as discussed in our response to comment 17 below.

Producing testing intervals: 2,863-2,871m; 2,922-2,924m; 2,930-2,975m; 3,009-3,017m

Current single interval production rate is 40-50 bpd.

With current completions, which include only one zone per well, the overall daily production rate range from the 6 wells is 1,266 to 2,100 bpd, depending on choke sizes and well bore conditions on the wells, etc. This, of course, is not representative of the cumulative total production rate from all of the tested intervals in each of the wells. The accumulated total for the tests on these wells are shown below:

Well	Interval, m	Influx	Choke size, Mm	Oil, bpd	Average
			6	184	
Aksaz 1	4249-4307	Oil and gas flow	8	250	245
			10	300	
			Total	245	
	4296-4293,		4	107	
	4272-4266,	Oil and gas flow	6	126	151
Aksaz 4	4261-4257		8	220	
	4304.9-4311,		4	76	
	4299-4305.1,	Oil and gas flow	6	113.4	105
	4298.8-4294.3	(high water)	8	126	
			Total	256	
	3521 - 3532	Production 5/04 to 3/05		172	172
Dolinnoe 1	3550 -3570	Production 4/05		133	133
	3631 - 3647	Production 5/05		146	146
			Total	451	
	3574.5-3577;				
	3578.4-3582;		6	83	
	3592 - 3597.4;				
Dolinnoe 2	3600-3609;	Oil and gas flow	8	100	97

	3611.5-3613.5;				
	3616-3627;				
	3628-3635.5;				
	3640.6-3641.7		10	107	

	3510.5-3512; 3513-3522	Oil and gas flow	6	239	243
			8	252	
			10	239	
			Total	340	
	3665.5-3682	Oil and gas flow	6	84	117
			8	132	
			10	135	
Dolinnoe 3	3639.7-3658.3; 3660-3663.6	Oil and gas flow	6	299	303
			8	303	
			10	306	
	3594.5-3600.6; 3603-3614.5	Oil and gas flow	6	1,415	1,580
			8	1,604	
			10	1,667	
			12	1,635	
			Total	2,000	
Emir 1	2933 - 2977	Production 7/05 (ave)		100	100
			Total	100	

The total capacity, based on cumulative test data for each well to date, is approximately 3,147 bpd.

Please note that all the tests and production rates for these wells are for production that is flowing from greater than 10,000 feet against a choked wellhead, prior to any stimulation. Because of the high reservoir pressure it has not been necessary to introduce artificial lift in any of the ADE Block fields, however, conventional stimulation techniques to improve production rates are being considered.

Chapman Petroleum Engineering Ltd has performed an Inflow Performance Relationship study to examine the maximum flow rates implied by the existing test data, assuming the wells were completely optimized with pumping equipment from the sand face up. Again this analysis would reflect pre-stimulation rates. The results indicate absolute maximum rates for the total of these wells including all combined zones of 8,814 STB/d. These rates, of course, are not realistically achievable, but the study demonstrates meaningful rate improvement potential with the implementation of conventional equipment.

The results of the study are tabulated on Appendix 1, attached hereto.

The Company proposes to incorporate much of the above information into the amended SB-2 filing under the sub-heading "Production" on page 32 to provide

additional disclosure about the results of testing and whether the Company believes these results are representative of the wells' long-term production trends.

Our Properties, page 36

7. You disclose that you own a 100% interest in a production license and the current royalty rate is 2%. You further disclose that when a commercial license is negotiated royalty rates can range from 2% to 6%. This would appear to give you a 94 to 98% net interest. However, we are not aware of any production contracts that are so beneficial to the grantee of the license. Disclose whether at any time the government has an option to participate or increase their net interest in the subject reserves. Provide us a copy of this contract or revise your document to make any corrections necessary in this disclosure. We may have further comment.

We own a 100% interest in an exploration license and the current royalty rate is 2%.

In accordance with the Kazakhstani fiscal regime, royalty rates vary from 2% to 6% depending on annual production volume. (Please see the following royalty rate scale).

The amount of government participation in our revenues is stipulated by our contract. The government is obligated to follow the contract terms and cannot increase its share of participation without changing appropriate legislation.

In addition to the royalty explained above, under the tax regime, the government collects corporate income tax of 30%. The government also collects an excess profits tax, which is applied after a number of deductions, and can be as high as 60% of the profits in excess of a prescribed rate of return for the Company.

Under this regime the Republic of Kazakhstan derives a share of production, which is comparable to many production sharing agreements around the world. The calculation of these taxes is presented in the Chapman Report. Also, a summary of the royalty provisions and applicable rates follows:

Royalty	Exploration	Production	Rates
Royalties shall be paid by a user of mineral resources separately for each type of minerals extracted on the territory of the Republic of Kazakhstan, regardless of whether they are sold (shipped) to buyers or used for ones own needs.	X	X	Royalty rates for hydrocarbons shall be established on a sliding scale as a percentage, determined in accordance with the extraction volume, for each year of activity, based on one of the following rates: Up to 500,000 tons - 2 percents; 500,000 tons to 1,000,000 tons - 2.5% 1,000,000 tons to 1,500,000 tons - 3% 1,500,000 tons to 2,000,000 tons - 3.5% 2,000,000 tons to 2,500,000 tons - 4% 2,500,000 tons to 3,500,000 tons - 4.5% 3,500,000 tons to 4,500,000 tons - 5 % 4,500,000 tons to 5,000,000 tons - 5.5% More than 5,000,000 tons - 6%

8. Please revise your filing to give the results of the well work you disclose such as the re-entering well in the Aksaz, Emir and Dolinnoe fields and the two new wells drilled in the Dolinnoe field.

Please see our response to comment 6 above. We propose to incorporate this information into the amended SB-2 filing.

9. Tell us if you are the operator of all of your oil and gas properties.

The Company is the operator of all of its oil and gas properties.

Title to Properties, page 39

10. You state that you believe you have satisfactory title to all our properties. As we understand you have an interest in a license to use subsurface mineral resources and a hydrocarbon exploration contract. However, this does not imply you have title or ownership in any reserves but only a contractual right to explore and produce. Please clarify your document as necessary.

We propose to revise the "Title to Properties" disclosure as follows:

Title to Properties

We hold an exploration contract from the Republic of Kazakhstan that grants us the right for exploration and test production of hydrocarbons on the ADE Block and the Extended Territory. Our rights to these properties will terminate in June 2007 unless we are able to negotiate an extension of our current exploration contract or we are granted a commercial production contract.

Results of Operations, page 42

Costs and Operating Expense, page 44

11. You state that you incurred $206,929 in "selling expenses" during the fiscal year ended March 31, 2005 but these costs were not included as operating costs. Please explain to us what this is.

We did not exclude "selling expenses" from operating costs. Selling expenses are included in the loss from operations as disclosed in the Consolidated Statements of Loss. If, however, the staff feels the current presentation is confusing, we would propose to revise this disclosure prospectively to present a single line item for "oil and gas operating expenses" that discloses all oil and gas operating expenses in a single line item, including selling expenses. The selling expenses were primarily transportation costs.

Revenue and Production, page 46

12. As you produced 41,456 barrels of oil for the three months ended June 30, 2005 and derived revenues of $662,637 in the same period it would appear that your average oil price was $15.98 per barrel and not $17.98 as you disclose. Also for the three months ended June 30, 2004 it appears the average oil price should be $10.43 per barrel. Please revise your document or explain to us why it is not necessary.

During the three months ended June 30, 2005 we produced 41,456 barrels of oil but only sold 36,854 barrels. The remaining barrels were placed into storage at our oil storage facility. Average oil price was calculated based the number of barrels sold, not the number of barrels produced. In other words, during the period we produced 41,456 we sold 36,854 barrels and realized revenue of $662,637, which equates to average price of $17.98 per barrel and retained in storage 4,602 barrel in storage.

The same situation occurred during the three months ended June 30, 2004, when we produced 11,405 barrels of oil but sold only 8,995 barrels of oil. The difference was placed in storage.

We propose to amend the SB-2 filing to provide a footnote to "Average Sales Price" to disclose that the Company may, at times, produce more barrels than it sells in a given period. The average sales price is calculated based on the average sales price per unit sold, not per unit produced.

Notes to the Consolidated Financial Statements, page F-7
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Long Term Liabilities, page F-16
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13. Tell us who PGS Reservoir Consultants are and the services they provide to you.

PGS Reservoir Consultants, a division of Petro Geo-Services ASA, is an independent service engineering company retained by the Company to interpret and analyze 2D Soviet seismic data of the ADE Block.

Supplementary Financial Information on Oil and Natural Gas Exploration Development and Production Activities (unaudited), page F-23
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14. Tell us why if you had 41.7 BCF of proved developed gas reserves, you had no gas production during FY 2005. Unless you can show evidence of long term gas contracts or a robust spot market we do not believe the gas reserves can be classified as proved. Tell us the source of the $0.50 per Mcf gas price used by the consultant in his report.

Gas reserves in the amount of 41.7 Bcf represents solution gas being produced with the oil. The gas is being measured with production in the case of the producing wells and is currently being flared. The gas reserves have not been assigned to the producing category, because the fields are not currently tied-in to the gas pipeline and currently gas is not being sold. Gas is shown in the developed non-producing category and the undeveloped category depending on the category of oil to which they relate.

The Company has been approached by a third party company with a proposal to install and jointly own gas processing facilities and to tie-in to the gas pipeline. The Company is currently performing due diligence with regard to the technology and the third party. The Company has also received correspondence from the local energy authority in Aktau, Kazakhstan, (the nearest city to the Company's fields) requesting that it tie its gas into the pipeline because of the need for gas in Aktau. The Company expects to tie the fields in with the gas pipeline and to be selling gas to the local market by the end of the 2006 calendar year.

The Company believes that its presentation of these reserves as proved (proved developed non-producing and proved undeveloped) is appropriate. Based on your comments, however, that gas cannot be considered proved until there is a contract in place for the sale of the gas, we agree to a reclassification of the 41.7 Bcf gas reserves from proven to probable in the Reserve Report of Chapman Petroleum and propose to make appropriate revisions in the amendment to the SB-2.

15. It appears from your oil production during FY 2005 it will take 198 years to produce just your developed oil reserves and 33 years to produce the proved producing reserves assuming oil production does not change. As all production will decline over time explain to us how this amount of developed reserves meets the requirements of reasonable certainty to be produced under Rule 4-10(a) of Regulation S-X.

While you are correct that based on our production during fiscal 2005 it would take 198 years to produce our develop oil reserves, that overlooks the fact that most of our developed reserves were still shut in at the time of our report. The proved developed reserves value of 13,614 MSTB would correspond to

an initial rate of about 1,950 STB/d at predicted initial rates for the total proved developed wells, once they are placed on production. This amounts to a reserve life index of 19 years. Of course, with declines the real life will be longer.

We agree with your calculated life of 33 years for the proved producing from the reserve value of 3,702 MSTB and a current rate of about 300 STB/d.

Please note that at the time of the report, the Dolinnoe 2 & 3 wells were not on production and the Emir 1 well was shut in, but all of these wells were classed as proved developed because they had already been drilled and were being tested. We estimated initial rates of about 500 STB/d per well for the Dolinnoe 2 & 3 wells, based on the cumulative tests for Dolinnoe 1. Dolinnoe 1 has never been on production from more than one individual interval, during 2005, but totaling rates from all the intervals tested results in greater than 500 STB/d.

These reserves qualify as proved reserves under Rule 4-10(a) of Regulation S-X on the basis that only zones in existing wells that have been tested or placed on production have been assigned reserves. Reserves have been established based on volumetric analysis, utilizing digital computerized log analysis and reasonable drainage areas and recovery factors. Zones that have been tested in one of the wells and correlate to the other wells, but that have not been tested in the other wells, have been considered tested in the accumulation. These wells are directly adjacent to each other.

16. There are several material differences between the undiscounted and discounted before and after tax cash flow numbers in the reserve report compared to the SMOG numbers in the filing. Please explain.

We have reviewed the SMOG numbers in the filing against the numbers in the reserve report and cannot identify any material discrepancies. Would you please provide us additional details as to which numbers you are referring?

Reserve Report as of April 1, 2005

17. We note for the proved developed consolidation of the 5 wells on the ADE Block you have assumed production will increase from 874.4 barrels of oil per day to 1,887.5 barrels of oil per day. Tell us what the current production from these wells are and the basis of assuming production from the existing wells will more than double in 2006.

The report assumes the non-producing Dolinnoe 2 & 3 wells would commence production by September 2005 at 500 STB/d each, as discussed above. We also expected a work-over of the Emir 1 well to result in 300 STB/d. This

resulted in the average production on the cash flow analysis, over the period from April to December 2005, to be 874 STB/d. In 2006 it was assumed that Dolinnoe 1 would be reconfigured to allow all zones to produce at once at a total rate of 500 STB/d, bringing the total yearly average to about 1,887.5 STB/d.

As disclosed in our response to comment 6, Emir 1 is currently producing less than our expectation. However, as we also disclosed in our response to comment 6, after the report date, the Dolinnoe 3 well, alone tested at cumulative rates from all zones of about between 1,500-1,625 STB/d depending on choke size. We are confident that production rates at Emir-1 can be increased and we plan to carry out additional activities, such as hydrofracturing and acid treatment, to increase production at that well.

For information regarding the production rates of each of our wells, please refer to our response to comment 6.

18. You have estimated each of these proved developed wells to have proved reserves of over 2.7 million barrels per well. Tell us how you arrived at this estimate and why it meets the requirements of reasonable certainty under Rule 4-10(a) of Regulation S-X.

As was stated in response to comment 15 above, the reserves qualify as proved reserves under Rule 4-10(a) of Regulation S-X on the basis that only zones in existing wells that have been tested or placed on production have been assigned reserves. Reserves have been established based on volumetric analysis, utilizing digital computerized log analysis and reasonable drainage areas and recovery factors. Zones that have been tested in one of the wells and correlate to the other wells, but that have not been tested in the other wells, have been considered tested in the accumulation. These wells are directly adjacent to each other.

There are also Triassic intervals in some wells which were identified as pay by log analysis, but which were not assigned reserves due to a lack of testing.

Additionally, there are significant hydrocarbons indicated by log analysis and drilling shows in the Jurassic formation, higher up hole in all these wells, that have had no reserves assigned because the Jurassic has not been sufficiently investigated by testing, to date and therefore do not qualify. The establishment of reserves in the Jurassic in this Block would have a significant impact.

19. We note that the decline rate of the Aksaz 1, 4 and the two proved undeveloped wells are estimated to be 2.0% per year. Tell us how you arrived at this estimated decline rate. We also note a very modest rise in the GOR over time for these wells. Tell us how you estimated this.

The low decline rates result from the combination of the initial rates scheduled in the report compared to the reserves assigned to the properties. The reserves are well substantiated and it would not seem to be appropriate to arbitrarily reduce the reserves to accommodate a production schedule that is not yet fully implemented. At fully optimized rates (see Q6.) the declines and depletion times would be much more as expected. Even though there is technical evidence suggesting these wells are capable of higher rates, the rates used in the report were restricted to those that have actually been achieved (at the time of the report), as a means of maintaining a conservative approach.

The GORs were not meant to increase. We expected that the gas will be tied-in during 2006, so it gives the appearance on the cash flows that the GOR increases in 2007.

20. Tell us the reason you make capital investments of $2 million in the 2005 and $3,500 million in 2006 for the proved developed reserves in the ADE Block.

The reserves were classified as developed because they were drilled, and in some cases on production. However, there was still some capital required for completion and testing for the two non-producing wells. We also included capital for a gas gathering system and well site facilities.

21. You cannot reduce the fixed costs after five years based only on an assumption that operations will "reach stability" by then. If costs are fixed, then it cannot be assumed that they will be materially lower at some point in the future. We are not clear on how fixed costs could change so dramatically but if these costs actually are materially reduced at sometime in the future, then at that time you may use lower costs in the reserve estimates. Until then please revise your estimate based on current fixed costs being held constant as required by Rule 4-10(a) of Regulation S-X.

Chapman Petroleum has rerun the economic analysis, as requested, implementing current operating costs held constant throughout.

In preparing the initial evaluation there was very little operating cost history on this property. In the absence of confirmed costs, to be conservative, Chapman Petroleum arbitrarily included an annual cost to account for unforeseen circumstances during the development stage of the property. After a few years these arbitrary costs were reduced. We have been advised that this reduction is not appropriate under SEC regulations and we acknowledge this.

To be fair, we have undertaken to reestablish the appropriate operating costs for the property, from more extensive data now available. In the

reassessment Chapman Petroleum has used variable costs of $2.00/STB and $8,000/well per month, which is supported by public reporting by the Company.

The results of Chapman Petroleum's reevaluation are presented in Appendix 2 to this Letter.

22. It is not appropriate to not attribute some general administration costs to the field operations. Please revise your estimate to incorporate these into your reserve estimate.

Chapman Petroleum has incorporated a G&A allocation $200,000 per month, reflecting the cost of the Company's Emir office, to its reevaluation. This cost was projected for the life of the project and the values are presented separately on the Summary of Results on the Total Proved level.

23. Provide us with the oil gravity and the reasons 80 and 160 acres and 30% are reasonably certain for the drainage area and the recovery factor for these wells. We do not feel that only anecdotal evidence about recovery efficiency is sufficient for proved reserves. Tell us the reservoir drive mechanism you assumed and the bubble point pressure of each of the reservoirs. Tell us the reason for assuming the gas-oil ratio will remain relatively stable over the productive life of the reservoir.

The API gravity of the Emir and Dolinnoe oil is 41 degrees. The oil at Aksaz is greater than 50 degrees API and is practically condensate.

A recovery factor of 30% has been assigned, based on input to Chapman Petroleum from various sources, including the Company's staff, other consultants who are familiar with the reservoirs in the basin and information from surrounding fields. The nearest similar fields, Alatobe and North Akkar have recognized recovery factors of 38% and 30%, respectively. These factors were established and are supported by prolonged production from these fields.

Although it is too early to confirm the depletion mechanism in the ADE fields, there is a high likelihood that these are water drive reservoirs. A review of the geological reference book for RoK reveals that most Triassic reservoirs in western Kazakhstan are influenced by water drive mechanisms. This is true for many other reservoir types, also. These Triassic reservoirs are located on a drape and do not have water contacts in the structurally high wells. Rather the water legs are located down structure, surrounding the oil accumulation providing pressure support without the risk of premature coning or encroachment.

To confirm the recovery factor assignment Chapman Petroleum has prepared an analysis with material balance equations based on fluid properties and reservoir parameters, for Emir and Dolinnoe. The results of this analysis

indicates recovery factors approaching 30% even under solution gas drive with no water drive influence. Influence from even partial water drive would improve on these indications. The same recovery has been assigned to Aksaz.

The technical analysis and summary of the procedure are contained in an Appendix 3 to this response. The basic reservoir and fluid parameters are shown below:

Emir : Initial Pressure - 5878 psi., Bubble Point Pressure - 3000 psi., Solution gas-oil-ratio - 673 scf/STB, Formation Volume Factor - 1.35 RB/STB

Dolinnoe : Initial Pressure - 7445 psi., Bubble Point Pressure - 4000 psi., Solution gas-oil-ratio - 1280 scf/STB, Formation Volume Factor - 1.78 RB/STB

This analysis does include the gradual increase of GOR with eventual recovery of about 85% of the solution gas for each pool. In the economic evalution the GOR was held at the current level, strictly to be conservative.

The reservoirs are between 30% and 40% over-pressured. The reservoirs are of good quality and there does not appear to be a threat of premature water encroachment, as no oil water contact can be seen in any of the wells in any zone. A drainage area of 160 acres is supported by the "State Balance of Oil Reserves of the Republic of Kazakhstan", which generally uses a 500 meter drainage radius (194 acres) as a minimum in this basin. Reservoir characteristics of the Dolinnoe oil field allow for a 1 km drainage area.

Alternatively, based on the same reserves, we could have assumed that infill wells would be drilled to reduce drainage areas of individual wells. This would require additional capital, but would result in higher rates and acceleration of the reserves assigned, undoubtedly increasing the NPV of the property. At this early stage of the development we have made the assumption of a 160 acre drainage per well, which considering the resulting long life of the reserves, may not be completely realistic, but is by far the most conservative model to portray future cash flows and NPV from the reserves assigned.

24. Tell us if you have core data and what that information is. Tell us the permeability values of the reservoirs in each field.

We have core samples from Dolinnoe 1, 2, and 3, Emir 1 and Aksaz 1 & 4. Permeabilities range from around 5 md to over 400 md. with a mid-range value of about 100 md. The core samples are in close agreement on water saturation and generally demonstrate a higher porosity than used in the report for our reserves, determined from log analysis.

25. Tell us if you limited proved reserves to lowest and highest known oil by well penetration.

Reserves in all zones were limited to only the pay zones that were tested, applied to a single drainage area for each well. The structure is reasonably flat and no water contacts have been detected in the existing wells for any zones that have been assigned reserves.

26. Tell us the total life of the proved reserves for each reservoir.

See our response to comment 15 and 19 above.

27. We note the Dolinnoe #1 well has declined at an approximate rate of 40% per year in 2004 and 2005. Therefore, it appears that your forecasted rates and decline rate cannot be supported. Please revise the reserves based on the actual performance to date.

The well was drilled during Soviet times before the Company acquired the ADE Block. Drilling commenced on June, 1990 and was completed on July 1994. There were two major down hole failures experienced during drilling. The well was tested on September 1995. The well bore has 25 degree spiral-formed deviated shape. The bottomhole area is polluted with formation debris and asphatene precipitation. In the newer wells, we are discovering paraffin precipitation, which is restricting production, but which is treatable. Our assumption is that this is the reason the production rate has been declining. The reservoir pressure was not measured since the gauge could not enter the wellbore. We think that the rate decline is occurring due to technical conditions of the well bore. In our opinion, reservoir energy is not declining at a rate of 40% per year. Also, it must be remembered that the full production life includes production from different zones, producing individually.

28. For the Emir proved undeveloped wells it is not appropriate to assume productive rates 3 times higher than the rates actually seen in the Emir #1 well. Please revise your estimates accordingly.

The Emir 1 well was drilled during Soviet times. When the well was initially tested there was a near blowout with reported rates of oil and mud of over 2,381 STB/d. The well was killed with some unknown heavy substance, which badly damaged the well. The well was re-entered and placed on production at an initial rate of about 180 STB/d flowing from 10,000 feet on a 4mm choke against over 700 psi well head pressure. The foreign material that invaded the zone soon plugged up the perforations and perhaps the immediate well bore and the well was shut in due to non commercial rates at the time of the latest report. Chapman Petroleum Engineering Ltd. reclassified the reserves as proved non-producing,

assuming a workover of the well would be performed. We believe the initial indicated rates and the surrounding wells' performance suggest the 300 STB/d rate is reasonable expectation.

29. It is not clear to us why 2 offset PUD Emir wells will have more than 5 times the reserves of the proved developed well. If this is due only to the initial higher production rates assigned to these wells, then the reserves should be reduced as the rates are reduced on the comment above. If there are other reasons for these higher reserves please indicate them to us or alternatively reduced the reserves.

For the proved undeveloped reserves we utilized exactly the same well bore parameters as for the Emir 1 well and the conventional 160 acre drainage used throughout the Block. The drainage area in the Emir 1 well was reduced to 80 acres because of the damage that had occurred during Soviet times to the well bore when killing the blowout, as discussed above. We would not expect the same occurrence with the wells to be drilled. The reserves thus were twice as much per well as the developed well simply due to the area assigned. Therefore, overall, the undeveloped reserves assigned are four times the developed.

We have confidence in the Emir field, even with the poor performance of the Emir 1 well. The technical analysis strongly supports the presence of producible hydrocarbons, especially with comparison to the other wells in this Block. Emir is productive from the same reservoir, the Triassic, as the Dolinnoe and Aksaz fields. All three fields are close to each other and are in the same geological environment. The well log analysis for all three fields demonstrate very similar characteristics and we believe the success thus far in Dolinnoe and Aksaz further supports the proved reserves assignment in Emir. Emir is located in an active area where the Triassic is a common oil producer. Emir wells should perform as well as any wells in the Block.

30. Tell us if you attribute proved reserves to the Lower Triassic interval in any of the three fields on the ADE Block. If so, tell us which ones. Tell us if the Lower Triassic has been production flow tested in any of the fields. If so, tell us the fields it was tested in and the results.

The Dolinnoe field has been assigned reserves in both the Upper and Lower Triassic, as we referred to it. Again, only tested or produced zones have been assigned reserves and the lower Triassic has been thoroughly tested in Dolinnoe.

We did not assign any reserves to the lower Triassic in Emir and for Aksaz we did not attempt to differentiate between what might be called upper or lower. The reserves here were assigned to an interval in the Lower Triassic based on log analysis and test data.

The Aksaz 1 and Dolinnoe wells have deposits that we assume belong to the Lower Triassic, as mentioned above, however, the exact stratification will be established after further paleontological research. Some of the intervals identified on logs are now being studied.

The neighboring North-West Zhetybay field and the Oimasha field located within 150 Km. are also productive from the Lower Triassic.

Thank you for your assistance in this matter. If you have any questions or require additional information, please contact me directly.

Very truly yours,

POULTON & YORDAN

/s/ Richard T. Ludlow

Richard T. Ludlow
Attorney at Law

Appendix 1
Productivity Analysis
ADE Block, Republic of Kazakhstan

Interval	Reservior Depth	Pressure	Oil rete	Gas-oil -ratio	Tubing Head Pressure	Sand Face Flowing Pressure	Product- ivity Index	Maximum Product- ivity

Well	meters	feet	psi	STB/d	scf/STB	psi	psi	-	STB/d	Comment
Aksaz # 1	4250 to 4275	13995	7677	166	2358	557	2500	0.0321	246	March 05 Production data
Dolinnoe #1	3521 to 3532	11562	7445	156	1234	762	3275	0.0374	279	March 05 production data
	3550 to 3570	11677	7519	133	1923	512	1925	0.0238	179	April 05 production data
	3641 to 3647	11936	7686	146	1235	440	2600	0.0287	221	May 05 production data
				435					678	
Dolinnoe #2	3510 to 3522	11545	7434	252	564	732	3700	0.0675	502	Test operations
	3574 to 3643	11808	7603	100	1457	732	3500	0.0244	185	Test operations
				352					687	
Dolinnoe #3	3594 to 3614	11821	7612	1666	600	2007	5587	0.8228	6263	Test operations
	3639 to 3663	11975	7711	303	581	-	1106	0.0459	354	Test operations
	3665 to 3682	12047	7757	132	957	-	4058	0.0357	277	Test operations
				2101					6894	
Emir #1	2933 to 2977	9692	5878	100	373	732	4000	0.0532	313	July 05 production data
Total Block (four wells)				3154					8818	

Appendix 2

Table 1 Constant Prices & Costs

Summary of Company Reserves and Economics

Before Income Tax

April 1, 2005

BMB MUNAI, INC.

ADE Block, Republic of Kazakhstan

Net To Appraised Interest

	Reserves								Cumulative Cash Flow (BIT) - M$				
	Light and Medium Oil MSTB		Sales Gas MMscf		NGL Mbbls		BOE Mbbls		Discounted at:				
Description	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undisc.	5%/year	10%/year	15%/year	20%/year
Proved Developed Producing													
Aksaz	1,861	1,824	0	0	0	0	1,861	1,824	28,982	12,465	7,652	5,563	4,408
Dolinnoe Field	1,841	1,804	0	0	0	0	1,841	1,804	32,011	20,871	15,181	11,858	9,715
Total Proved Developed Producing	3,702	3,628	0	0	0	0	3,702	3,628	60,993	33,336	22,832	17,421	14,123
Proved Developed Non-Producing													
Dolinnoe Field	6,879	6,741	0	0	0	0	6,879	6,741	121,384	66,819	45,409	34,312	27,552
Emir	3,033	2,973	0	0	0	0	3,033	2,973	52,386	25,174	15,755	11,319	8,785
Total Proved Developed Non-Producing	9,912	9,714	0	0	0	0	9,912	9,714	173,770	91,993	61,165	45,631	36,336
Total Proved Developed	13,614	13,342	0	0	0	0	13,614	13,342	234,763	125,329	83,997	63,052	50,459
Proved Undeveloped													
Aksaz	5,630	5,517	0	0	0	0	5,630	5,517	74,349	22,440	8,275	2,730	47
Dolinnoe Field	2,580	2,528	0	0	0	0	2,580	2,528	38,038	16,947	9,037	5,223	3,074
Emir	12,134	11,891	0	0	0	0	12,134	11,891	209,069	54,593	22,594	11,853	6,833
Total Proved Undeveloped	20,344	19,937	0	0	0	0	20,344	19,937	321,456	93,980	39,906	19,806	9,954
Total Proved	33,958	33,279	0	0	0	0	33,958	33,279	556,219	219,309	123,903	82,857	60,413
Probable													
Probable Undeveloped													
Aksaz	1,877	1,839	19,921	19,522	0	0	5,197	5,093	26,517	8,441	2,424	(82)	(1,262)
Dolinnoe Field	20,636	20,224	35,449	34,740	0	0	26,544	26,014	317,515	155,535	86,001	50,821	30,956
Emir	36,447	35,718	46,338	45,411	0	0	44,170	43,287	638,183	211,336	102,296	59,110	37,086
Total Probable Undeveloped	58,960	57,782	101,708	99,673	0	0	75,911	74,394	982,214	375,312	190,721	109,849	66,781
Total Proved Plus Probable	92,918	91,061	101,708	99,673	0	0	109,869	107,674	1,538,434	594,621	14,624	192,706	127,194

Gross reserves are the total of the Company's working and/or royalty interest share before deduction of royalties owned by others.
Net reserves are the total of the Company's working and/or royalty interest share after deducting the amounts attributable to royalties owned by others.
Columns may not add precisely due to accumulative rounding of values throughout the report. Reserves quoted in BOE calculated using a conversion of 6 Mscf/bbl (6:1).

Table 1T Constant Prices & Costs

Summary of Company Reserves and Economics

After Income Tax

April 1, 2005

BMB MUNAI, INC.

ADE Block, Republic of Kazakhstan

Net To Appraised Interest

Description	Reserves: Light and Medium Oil MSTB Gross	Net	Sales Gas MMscf Gross	Net	NGL Mbbls Gross	Net	BOE Mbbls Gross	Net	Cumulative Cash Flow (BIT) - M$ Discounted at: Undisc.	5%/year	10%/year	15%/year	20%/year
Proved													
Total Proved (BIT)	33,958	33,279	0	0	0	0	33,958	33,279	556,219	219,309	123,903	82,857	60,413
Corporate G&A	-	-	-	-	-	-	-	-	(120,000)	(44,896)	(24,957)	(17,142)	(13,144)
Corporate Income Tax	-	-	-	-	-	-	-	-	(124,580)	(37,431)	(20,629)	(14,143)	(10,432)
Excess Profits Tax	-	-	-	-	-	-	-	-	(137,783)	(37,712)	(18,846)	(11,875)	(8,066)
Total Proved After G&A and Income Tax	33,958	33,279	0	0	0	0	33,958	33,279	173,857	99,270	59,472	39,697	28,771
Probable													
Total Probable (BIT)	58,960	57,782	101,708	99,673	0	0	75,911	74,394	982,214	375,312	190,721	109,849	66,781
Corporate Income Tax	-	-	-	-	-	-	-	-	(315,440)	(91,493)	(48,316)	(31,806)	(22,507)
Excess Profits Tax	-	-	-	-	-	-	-	-	(409,953)	(110,007)	(54,596)	(34,529)	(23,642)
Total Probable After G&A and Income Tax	58,960	57,782	101,708	99,673	0	0	75,911	74,394	256,822	173,811	87,809	43,514	20,633
Total Proved Plus Probable After G&A and Income Tax	92,918	91,061	101,708	99,673	0	0	109,869	107,674	430,679	273,081	147,281	83,211	49,404

Gross reserves are the total of the Company's working and/or royalty interest share before deduction of royalties owned by others.
Net reserves are the total of the Company's working and/or royalty interest share after deducting the amounts attributable to royalties owned by others.
Columns may not add precisely due to accumulative rounding of values throughout the report. Reserves quoted in BOE calculated using a conversion of 6 Mscf/bbl (6:1).

Table 2

EVALUATION OF: ADE Block, Kazakhstan ERGO v6.00g PETRO-SOFT SYSTEMS LTD. GRAND TOTAL

Total Proved Consolidation GLOBAL : 11-JUL-2005 3864_BMB_C$

EFF DATE: 01-APR-2005

RUN DATE: 13-JAN-2006 TIME: 17:54

FILE:

EVALUATED BY -

COMPANY EVALUATED - BMB MUNAI INC.

APPRAISAL FOR -

PROJECT - CONSTANT PRICES & COSTS

TOTAL CAPITAL COSTS - 34000000 -$-

TOTAL ABANDONMENT - 550000 -$-

Oil

MSTB

Year	# of Wells	Price $/STB	Pool MSTB/d	Vol	Company Share Gross	Net
2005	5	21.27	0.9	240	240	236
2006	7	21.39	2.4	807	807	791
2007	11	21.29	4.1	1,072	1,072	1,051
2008	11	21.25	8.4	1,125	1,125	1,102
2009	11	21.25	10.1	1,088	1,088	1,066
2010	11	21.25	9.5	1,050	1,050	1,029
2011	11	21.24	9.1	1,014	1,014	994
2012	11	21.24	8.7	975	975	956
2013	11	21.24	8.3	940	940	921
2014	11	21.24	7.9	906	906	888
2015	11	21.23	7.6	874	874	857
2016	11	21.23	7.3	844	844	827
2017	11	21.23	7.0	815	815	799
2018	11	21.22	6.7	787	787	771
2019	11	21.22	6.4	761	761	745
SUB				13,299	13,299	13,033
REM				20,658	20,658	20,245
TOT				33,954	33,954	33,279

= POOL/TRACT = ==================================== COMPANY SHARE REVENUE AND CASH FLOW ==

Year	Oper Costs M$	Capital Costs M$	Gross Revenue Sales Oil M$	Gas M$	Pro-ducts M$	Total M$	Royalties Crown M$	Other M$	Min-eral M$	%	Operating Costs Fixed M$	Vari-able M$	Net $/BOE	Net Revenue M$	Net $/BOE	Proc & Other Income M$	Capi-tal Costs M$	Cash Flow Undisc. M$	PW 10% M$
2005	721	3,500	5,114	0	0	5,114	102	0	0	2.0	240	481	3.00	4,291	17.84	0	3,500	791	763
2006	2,239	6,500	17,197	0	0	17,197	344	0	0	2.0	624	1,615	2.77	14,614	18.10	0	6,500	8,114	7,200
2007	3,073	24,000	22,824	0	0	22,824	456	0	0	2.0	928	2,145	2.87	192,29	17.99	0	24,000	(4,705)	(3,795)
2008	3,306	0	23,904	0	0	23,904	478	0	0	2.0	1,056	2,250	2.94	20,121	17.89	0	0	20,121	14,756
2009	3,232	0	23,116	0	0	23,116	462	0	0	2.0	1,056	2,176	2.97	19,422	17.85	0	0	19,422	12,949
2010	3,156	0	22,308	0	0	22,308	446	0	0	2.0	1,056	2,100	3.01	18,706	17.82	0	0	18,706	11,338
2011	3,084	0	21,544	0	0	21,544	431	0	0	2.0	1,056	2,028	3.04	18,029	17.78	0	0	18,029	9,934
2012	3,007	0	20,717	0	0	20,717	414	0	0	2.0	1,056	1,951	3.08	17,297	17.73	0	0	17,297	8,664
2013	2,936	0	19,964	0	0	19,964	399	0	0	2.0	1,056	1,880	3.12	16,629	17.69	0	0	16,629	7,572
2014	2,869	0	19,247	0	0	19,247	385	0	0	2.0	1,056	1,813	3.07	15,994	17.65	0	0	15,994	6,621
2015	2,805	0	18,565	0	0	18,565	371	0	0	2.0	1,056	1,749	3.21	15,389	17.60	0	0	15,389	5,792
2016	2,744	0	17,916	0	0	17,916	358	0	0	2.0	1,056	1,688	3.25	14,813	17.55	0	0	14,813	5,068
2017	2,686	0	17,296	0	0	17,296	346	0	0	2.0	1,056	1,630	3.30	14,265	17.51	0	0	14,265	4,437
2018	2,630	0	16,705	0	0	16,705	334	0	0	2.0	1,056	1,574	3.34	13,741	17.46	0	0	13,742	3,885
2019	2,577	0	16,142	0	0	16,142	323	0	0	2.0	1,056	1,521	3.39	13,242	17.41	0	0	13,242	3,404
SUB	41,063	34,000	282,561	0	0	282,561	5,561	0	0	2.0	14,464	26,599		235,847		0	34,000	201,847	98,588
REM	74,568	550	438,256	0	0	438,256	8,765	0	0	2.0	33,252	41,317		354,922		0	550	354,372	25,315
TOT	115,633	4,550	720,816	0	0	720,816	14,416	0	0	2.0	47,716	67,915		590,769		0	34,550	556,219	123,903

===================== PRESENT WORTH (-M$-)========================

Discount Rate	0%	5%	10%	15%	20%
Revenue	590,769	250,423	152,418	109,151	84,768
Proc & Other Income	0	0	0	0	0
Capital Costs	34,000	31,052	28,506	26,29	224,354
Abandonment Cost	550	62	9	2	0
Cash Flow	556,219	219,309	123,903	82,857	60,413

================= PROFITABILITY =========

COMPANY SHARE BASIS	Before Tax
Rate of Return (%)	999.9
Profit Index (undisc.)	16.1
(disc. @ 10.0%)..........	4.3
(disc. @ 5.0%)..........	7
First Payout (years)	0.7
Total Payout (years)	2.6
Cost of Finding ($/BOE)	1.02
PW @ 10.0% ($/BOE)	3.65
PW @ 5.0% ($/BOE)	6.46

================================COMPANY SHARE==

	1st Year	Averag	Royaltities	Operating Costs	Net Revenue	Capitals Costs	Cash Flow
% Interest	100.0	100.0					
% of Gross Revenue ..			2.0	16.0	82.0	4.8	77.2

Continued...

Table 2 continued
BMB Munai
Allocation of G&A
ADE Block, Republic of Kazakhstan

Year	Undiscounted G&A M$/yr.	Discounted @ 5% M$	10% M$	15% M$	20% M$
2005	2,400	2,342	2,288	2,238	2,191
2006	2,400	2,231	2,080	1,946	1,826
2007	2,400	2,124	1,891	1,692	1,521
2008	2,400	2,023	1,719	1,472	1,268
2009	2,400	1,927	1,563	1,280	1,057
2010	2,400	1,835	1,421	1,113	880
2011	2,400	1,748	1,292	968	734
2012	2,400	1,665	1,174	841	611
2013	2,400	1,585	1,068	732	510
2014	2,400	1,510	970	636	425
2015	2,400	1,438	882	553	354
2016	2,400	1,369	802	481	295
2017	2,400	1,304	729	418	246
2018	2,400	1,242	663	364	205
2019	2,400	1,183	603	316	171
Sub Total	36,000	25,526	19,146	15,049	12,292
Rem	84,000	19,370	5,811	2,093	852
Total	120,000	44,896	24,957	17,142	13,144

Table 2 cont...
Company
Corporate Income Tax (CIT) and Excess Profit Tax (EPT)
January 1, 2005
Area, Kazakhstan
Total Proved

Year	Gross Income $M	Operating Costs and G&A $M	Royalties $M	Deductible Capital $M	Total Deductions $M	Taxable Income $M	Corporate Income Tax $M
		Deductible Costs					
2005	5,114	3,121	102	1,891	5,114	0	0
2006	17,197	4,639	344	9,109	14,092	3,105	932
2007	22,824	5,473	456	11,100	17,029	5,795	1,739
2008	23,904	5,706	478	11,100	17,284	6,620	1,986
2009	23,116	5,632	462	11,100	17,194	5,922	1,777
2010	22,308	5,556	446	6,400	12,402	9,906	2,972
2011	21,544	5,484	431	4,800	10,715	10,829	3,249
2012	20,717	5,407	414	0	5,821	14,896	4,469
2013	19,964	5,336	399	0	5,735	14,229	4,269
2014	19,247	5,269	385	0	5,654	13,593	4,078
2015	18,565	5,205	371	0	5,576	12,989	3,897
2016	17,916	5,144	358	0	5,502	12,414	3,724
2017	17,296	5,086	346	0	5,432	11,864	3,559
2018	16,705	5,030	334	0	5,364	11,341	3,402
2019	16,142	4,977	323	0	5,300	10,842	3,253
Sub total	282,561	77,065	5,651	55,500	138,216	144,345	43,304
Remainder	438,256	158,569	8,765	0	167,334	270,922	81,276
Total	720,816	235,634	14,416	55,500	305,550	415,267	124,580

Year	Net Income $M	20% of Deductions $M	Tax Base $M	Ratio Net Income to Deductions %	Amount Exceeding 20% %	EPT Rate %	EPT Amount $M
2005	0	1,023	-1,023	0	0	0	0
2006	2,174	2,818	-645	15	-5	15	0
2007	4,057	3,406	651	24	4	15	98
2008	4,634	3,457	1,177	27	7	30	353
2009	4,145	3,439	707	24	4	15	106
2010	6,934	2,480	4,454	56	36	60	2,672
2011	7,580	2,143	5,437	71	51	60	3,262
2012	10,427	1,164	9,263	179	159	60	5,558
2013	9,960	1,147	8,813	174	154	60	5,288
2014	9,515	1,131	8,384	168	148	60	5,031
2015	9,092	1,115	7,977	163	143	60	4,786
2016	8,690	1,100	7,589	158	138	60	4,554
2017	8,305	1,086	7,218	153	133	60	4,331
2018	7,939	1,073	6,866	148	128	60	4,119
2019	7,589	1,060	6,529	143	123	60	3,918
Sub total	101,042	27,643	73,398	1,503	1,223	675	44,076
Remainder	189,645	33,467	156,178	113	93	60	93,707
Total	290,687	61,110	229,577	1,616	1,316	735	137,783

Net Present Values

	Discout Factors - %/yr.				
	0	5	10	15	20
Corporate Income Tax	124,580	37,431	20,629	14,143	10,432
Excess Profits Tax	137,783	37,712	18,846	11,875	8,066

Table 3

EVALUATION OF: ADE Block, Kazakhstan
Total Proved Plus Probable Consolidation

ERGO v6.00g PETRO-SOFT SYSTEMS LTD. GRAND TOTAL
GLOBAL : 11-JUL-2005 3864_BMB_C$
EFF DATE: 01-APR-2005
RUN DATE: 17-JAN-2006 TIME: 15:13
FILE:

EVALUATED BY -
COMPANY EVALUATED - BMB MUNAI INC.
APPRAISAL FOR -
PROJECT - CONSTANT PRICES & COSTS

TOTAL CAPITAL COSTS - 143000000 -$-
TOTAL ABANDONMENT - 1300000 -$-

	Oil MSTB						Gas MMCF					
			Pool		Company Share				Pool		Company Share	
Year	# of Wells	Price $/STB	MSTB/d	Vol	Gross	Net	# of Wells	Price $/MCF	MMCF/d	Vol	Gross	Net
2005	5	21.31	0.9	240	240	236	0	0.50	0.0	0	0	0
2006	7	21.32	2.4	880	880	863	0	0.50	1.6	567	567	555
2007	19	21.33	4.1	1,506	1,506	1,476	0	0.50	4.6	1,680	1,680	1,646
2008	23	21.34	8.4	3,083	3,083	3,021	0	0.50	9.6	3,490	3,490	3,420
2009	26	21.34	10.1	3,679	3,679	3,606	0	0.50	11.3	4,125	4,125	4,042
2010	26	21.34	9.5	3,472	3,472	3,403	0	0.50	10.7	3,897	3,897	3,819

2011	26	21.34	9.1	3,310	3,310	3,243	0	0.50	10.2	3,717	3,717	3,643
2012	26	21.34	8.7	3,164	3,164	3,101	0	0.50	9.7	3,554	3,554	3,482
2013	26	21.34	8.3	3,027	3,027	2,966	0	0.50	9.3	3,400	3,400	3,332
2014	26	21.33	7.9	2,897	2,897	2,839	0	0.50	8.9	3,254	3,254	3,189
2015	26	21.33	7.6	2,774	2,774	2,719	0	0.50	8.5	3,116	3,116	3,054
2016	26	21.33	7.3	2,658	2,658	2,605	0	0.50	8.2	2,985	2,985	2,926
2017	26	21.33	7.0	2,547	2,547	2,497	0	0.50	7.8	2,862	2,862	2,804
2018	26	21.33	6.7	2,442	2,442	2,393	0	0.50	7.5	2,743	2,743	2,688
2019	26	21.33	6.4	2,342	2,342	2,296	0	0.50	7.2	2,632	2,632	2,579
SUB				38,023	38,023	37,263				42,021	42,021	41,180
REM				54,895	54,895	53,797				59,687	59,687	58,493
TOT				92,918	92,918	91,060				101,708	101,708	99,673

= POOL/TRACT = ================================== COMPANY SHARE REVENUE AND CASH FLOW ===

Year	Oper Costs	Capital Costs	Gross Revenue: Sales Oil	Gross Revenue: Gas	Gross Revenue: Products	Total	Royalties: Crown	Royalties: Other	Royalties: Mineral	%	Operating Costs: Fixed	Operating Costs: Variable	Net $/BOE	Net Revenue	$/BOE	Proc & Other Income	Capital Costs	Cash Flow: Undisc.	Cash Flow: PW 10%
	M$	M$	M$	M$	M$	M$	M$	M$	M$	%	M$	M$	$/BOE	M$	$/BOE	M$	M$	M$	M$
2005	721	4,500	5,114	0	0	5,114	102	0	0	2.0	240	481	3.00	4,291	17.84	0	4,500	(209)	(202)
2006	2,479	11,000	18,759	283	0	19,042	381	0	0	2.0	624	1,855	2.54	16,182	16.60	0	11,000	5,182	4,599
2007	4,605	79,500	32,118	840	0	32,958	659	0	0	2.0	1,312	3,293	2.58	27,694	15.50	0	79,500	(51,806)	(41,793)
2008	8,955	48,000	65,749	1,745	0	67,494	1,350	0	0	2.0	2,208	6,747	2.44	57,189	15.61	0	48,000	9,189	6,739
2009	10,542	0	78,524	2,062	0	80,586	1,612	0	0	2.0	2,496	8,046	2.41	68,432	15.67	0	0	68,432	45,625
2010	10,090	0	74,105	1,949	0	76,054	1,521	0	0	2.0	2,496	7,594	2.45	64,443	15.63	0	0	64,443	39,059
2011	9,735	0	70,626	1,858	0	72,484	1,450	0	0	2.0	2,496	7,239	2.48	61,299	15.60	0	0	61,299	33,777
2012	9,416	0	67,511	1,777	0	69,288	1,386	0	0	2.0	2,496	6,920	2.51	58,486	15.57	0	0	58,486	29,296
2013	9,116	0	64,579	1,700	0	66,279	1,326	0	0	2.0	2,496	6,620	2.54	55,837	15.54	0	0	55,837	25,427
2014	8,833	0	61,814	1,627	0	63,441	1,269	0	0	2.0	2,496	6,337	2.57	53,339	15.51	0	0	53,339	22,081
2015	8,564	0	59,183	1,558	0	60,741	1,215	0	0	2.0	2,496	6,068	2.60	50,962	15.47	0	0	50,962	19,179
2016	8,309	0	56,694	1,493	0	58,187	1,164	0	0	2.0	2,496	5,813	2.63	48,714	15.44	0	0	48,714	16,667
2017	8,068	0	54,340	1,431	0	55,771	1,115	0	0	2.0	2,496	5,572	2.67	46,588	15.40	0	0	46,588	14,490
2018	7,837	0	52,089	1,372	0	53,461	1,069	0	0	2.0	2,496	5,341	2.70	44,555	15.37	0	0	44,555	12,598
2019	7,620	0	49,960	1,316	0	51,276	1,026	0	0	2.0	2,496	5,124	2.74	42,630	15.33	0	0	42,630	10,958
SUB	114,88	143,000	811,16	721,010	0	832,177	16,644	0	0	2.0	31,840	83,049		700,644		0	143,000	557,644	238,500
REM	194,18	41,300	1,170,436	429,843		01,200,279	24,006	0	0	2.0	74,446	119,738		982,090		0	1,300	980,790	76,124
TOT	309,07	144,300	1,981,603	650,854		02,032,457	40,649	0	0	2.0	106,286	202,788		1,682,735		0	144,3001,538,435		314,625

============= PRESENT WORTH (-M$-)===============

Discount Rate	0%	5%	10%	15%	20%
Revenue	1,682,734	721,721	428,087	294,696	219,388
Proc & Other Income..	0	0	0	0	0
Capital Costs............	143,000	126,943	113,440	101,986	92,193
Abandonment Costs........	1,300	156	23	4	1
Cash Flow	1,538,434	594,621	314,624	192,706	127,194

============ PROFITABILITY ================

COMPANY SHARE BASIS	Before Tax
Rate of Return (%)	90
Profit Index (undisc.)	107
(disc. @ 10.0%)	2.8
(disc. @ 5.0%)	4.7
First Payout (years)	0.8
Total Payout (years)	4.3
Cost of Finding ($/BOE)	1.31
PW @ 10.0% ($/BOE)	2.86
PW @ 5.0% ($/BOE)	5.41

=================================== COMPANY SHARE ===================================

	1st Year	Averag	Operating Royaltities	Net Costs	Capitals Revenue	Cash Costs	Flow
% Interest	100.0	100.0					
% of Gross Revenue .			2.0	15.2	82.8	7.1	75.7

Table 3 cont...
Company
Corporate Income Tax (CIT) and Excess Profit Tax (EPT)
January 1, 2005
Area, Kazakhstan
Total Proved Plus Probable

Year	Gross Income $M	Deductible Costs: Operating Costs and G&A $M	Deductible Costs: Royalties $M	Deductible Costs: Deductible Capital $M	Deductible Costs: Total Deductions $M	Taxable Income $M	Corporate Income Tax $M
2005	5,114	3,121	102	1,891	5,114	0	0
2006	19,043	4,879	381	10,109	15,369	3,674	1,102
2007	32,958	7,005	659	23,000	30,664	2,294	688
2008	67,494	11,355	1,350	32,600	45,305	22,189	6,657
2009	80,587	12,942	1,612	32,600	47,154	33,433	10,030
2010	76,054	12,490	1,521	27,700	41,711	34,343	10,303
2011	72,485	12,135	1,450	25,500	39,085	33,400	10,020
2012	69,288	11,816	1,386	9,600	22,802	46,486	13,946
2013	66,278	11,516	1,326	0	12,842	53,436	16,031
2014	63,441	11,233	1,269	0	12,502	50,939	15,282
2015	60,741	10,964	1,215	0	12,179	48,562	14,569
2016	58,187	10,709	1,164	0	11,873	46,314	13,894
2017	55,771	10,468	1,115	0	11,583	44,189	13,257
2018	53,461	10,237	1,069	0	11,306	42,155	12,647

2019	51,276	10,020	1,026	0	11,046	40,230	12,069
Sub total	832,177	150,890	16,644	163,000	330,534	501,644	150,493
Remainder	1,200,279	211,184	24,006	0	235,190	965,090	289,527
Total	2,032,457	362,074	40,649	163,000	565,723	1,466,734	440,020

Year	Net Income $M	20% of Deductions $M	Tax Base $M	Ratio Net Income to Deductions %	Amount Exceeding 20% %	EPT Rate %	EPT Amount $M
2005	0	1,023	-1,023	0	0	0	0
2006	2,572	3,074	-502	17	-3	15	0
2007	1,606	6,133	-4,527	5	-15	15	0
2008	15,532	9,061	6,471	34	14	30	1,941
2009	23,403	9,431	13,972	50	30	45	6,288
2010	24,040	8,342	15,698	58	38	60	9,419
2011	23,380	7,817	15,563	60	40	60	9,338
2012	32,540	4,560	27,980	143	123	60	16,788
2013	37,405	2,568	34,837	291	271	60	20,902
2014	35,657	2,500	33,157	285	265	60	19,894
2015	33,993	2,436	31,558	279	259	60	18,935
2016	32,420	2,375	30,045	273	253	60	18,027
2017	30,932	2,317	28,615	267	247	60	17,169
2018	29,509	2,261	27,248	261	241	60	16,349
2019	28,161	2,209	25,952	255	235	60	15,571
Sub total	351,151	66,107	285,044	2,278	1,998	705	170,620
Remainder	675,563	47,038	628,525	287	267	60	377,115
Total	1,026,714	113,145	913,569	2,565	2,265	765	547,735

Net Present Values

	Discount Factors - %/yr.				
	0	5	10	15	20
Corporate Income Tax	440,020	128,925	68,945	45,949	32,938
Excess Profits Tax	547,735	147,719	73,442	46,404	31,707

Appendix 3